



An **ATCO** Company

**MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION
AND RESULTS OF OPERATIONS**

**FOR THE YEAR ENDED
DECEMBER 31, 2004**

CU INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

The following discussion and analysis of financial condition and results of operations of CU Inc. (the "Corporation") should be read in conjunction with the Corporation's unaudited comparative interim financial statements for the three months ended December 31, 2004, and the audited comparative financial statements for the year ended December 31, 2004. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

All quarterly information in this document is shaded to differentiate it from the annual information.

The common share capital of the Corporation consists of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

TABLE OF CONTENTS

	<u>Page</u>
Forward-Looking Information	2
Business of the Corporation.....	3
Transfer of the Retail Energy Supply Businesses	3
Selected Annual and Quarterly Information	4
Results of Operations.....	5
Consolidated Operations.....	5
Segmented Information.....	8
Utilities.....	9
Power Generation.....	10
Regulatory Matters	11
ATCO Electric	11
ATCO Gas	12
ATCO Pipelines	12
Liquidity and Capital Resources.....	13
Outstanding Share Data	16
Transactions With Related Parties	17
Business Risks	18
Off-Balance Sheet Arrangements	20
Critical Accounting Estimates	21
Changes in Accounting Policies	21

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to purchase obligations, planned capital expenditures, anticipated completion dates and construction costs of major projects, and the impact of changes in government regulation. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the

Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from two segments: utilities and power generation (refer to Note 21 of the comparative financial statements). Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information.

The **Utilities** segment includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, and the regulated transmission and distribution of water by CU Water. This segment was formerly known as Natural Gas and Electric; its composition has remained unchanged.

The **Power Generation** segment consists of the regulated supply of electricity by Alberta Power (2000).

TRANSFER OF THE RETAIL ENERGY SUPPLY BUSINESSES

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc ("Transfer of the Retail Energy Supply Businesses"). Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of \$63.3 million before income taxes of \$8.2 million. This transfer increased 2004 earnings by \$55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004, will be reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There will be no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions (the "transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm, commercial and small industrial customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the Alberta Energy and Utilities Board ("AEUB") to do so), the agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a \$300 million guarantee supported by a \$235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services, an affiliate corporation, in respect of the ongoing relationships contemplated under the transaction agreements. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below

\$200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

SELECTED ANNUAL AND QUARTERLY INFORMATION

(\$ Millions except per share data)	For the Three Months Ended				Year Ended
	Mar. 31	Jun. 30	Sep. 31	Dec. 31	Dec. 31
	<i>(unaudited)</i>				
2004					
Revenues (1)	960.0	480.7	266.3	371.7	2,078.7
Earnings attributable to Class A and Class B shares (2) (5) (6).....	63.8	80.3	24.0	53.5	221.6
2003					
Revenues.....	1,099.2	588.7	430.2	728.1	2,846.2
Earnings attributable to Class A and Class B shares (3) (5) (6).....	62.7	32.5	25.2	54.4	174.8
2002					
Revenues.....					2,236.4
Earnings attributable to Class A and Class B shares (3) (4) (5) (6).....					225.4

Notes:

- (1) Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, September 30, 2004 and December 31, 2004.
- (2) Includes earnings of \$55.1 million on the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, and for the year ended December 31, 2004.
- (3) 2003 and 2002 earnings attributable to Class A and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations.
- (4) Includes earnings of \$67.3 million on the sale of the Viking-Kinsella natural gas producing property for the year ended December 31, 2002.
- (5) There were no discontinued operations or extraordinary items during these periods.
- (6) Due to the seasonal nature of the Corporation's operations and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.
- (7) As all Class A and Class B shares of the Corporation are owned by Canadian Utilities Limited, the disclosure of earnings per share is not provided as it is not considered to be meaningful.
- (8) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

	Year Ended December 31		
	2004	2003	2002
	(\$ Millions except per share data)		
Cash dividends declared per share (1):			
Series Second Preferred Shares:			
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series U	1.26	1.26	1.26
Series V (2).....	1.31	1.31	1.17
Total assets	4,185.0	4,205.4	3,960.0
Long term debt.....	2,062.5	1,682.5	1,743.5
Equity preferred shares	256.5	256.5	256.5
Class A and Class B share owners' equity.....	1,443.9	1,411.0	1,332.8

Notes:

- (1) Dividends declared by subsidiary companies of CU Inc. on preferred shares held by Canadian Utilities Limited.
(2) The dividend was reset to \$1.31 (5.25%) for the period between October 3, 2002 and October 3, 2007.
(3) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

RESULTS OF OPERATIONS

The principal factors that have caused variations in **revenues** over the eight most recently completed quarters were:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses section), and lower prices of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004 (refer to the Utilities section);
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections); and
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004 (refer to the Power Generation section).

The principal factors that have caused variations in **earnings** over the eight most recently completed quarters were:

- the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses and the Utilities sections);
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections); and
- timing of plant outages in Alberta Power (2000) (refer to the Power Generation section).

Consolidated Operations

Revenues for the three months ended December 31, 2004, decreased by \$356.4 million to \$371.7 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and
- warmer temperatures in ATCO Gas, which were 9.8% warmer than normal, compared to 3.2% warmer than normal for the corresponding period in 2003.

This decrease was partially offset by:

- the ATCO Pipelines Decision (refer to Regulatory Matters - ATCO Pipelines section).

Revenues for the year ended December 31, 2004, decreased by \$767.5 million to \$2,078.7million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas, which were 3.0% warmer than normal, compared to 3.4% colder than normal in 2003;
- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- customer additions in ATCO Gas; and
- the ATCO Pipelines Decision.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2004, decreased by \$0.9 million to \$53.5 million, primarily due to:

- higher transportation costs in ATCO Pipelines;
- warmer temperatures in ATCO Gas; and
- the ATCO Gas Decision (refer to Regulatory Matters - ATCO Gas section).

This decrease was partially offset by:

- the ATCO Pipelines Decision; and
- lower income tax rates.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2004, **including** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, increased by \$46.8 million to \$221.6 million.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2004, **excluding** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by \$8.3 million to \$166.5 million, primarily due to:

- warmer temperatures in ATCO Gas;
- the ATCO Electric Decision (refer to Regulatory Matters - ATCO Electric section); and
- higher transportation costs in ATCO Pipelines.

This decrease was partially offset by:

- lower income tax rates;
- the ATCO Pipelines Decision; and
- customer additions in ATCO Gas.

Return on common equity was 15.5% in 2004.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2004, decreased by \$361.8 million to \$198.7 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses;
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs);
- lower selling and administrative costs, primarily in ATCO Gas and ATCO Electric; and
- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher franchise fees in ATCO Gas; and
- higher transportation costs in ATCO Pipelines.

Operating expenses for the year ended December 31, 2004, decreased by \$757.9 million to \$1,451.3 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower costs of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas;
- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004; and
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs).

This decrease was partially offset by:

- customer additions in ATCO Gas;
- higher transportation costs in ATCO Pipelines; and
- higher franchise fees in ATCO Gas.

Depreciation and amortization expenses for the three months ended December 31, 2004, increased by \$7.0 million to \$63.5 million, primarily due to:

- capital additions in 2004 and 2003.

Depreciation and amortization expenses for the year ended December 31, 2004, increased by \$15.3 million to \$222.4 million, primarily due to:

- capital additions in 2004 and 2003.

Interest expense for the three months ended December 31, 2004, increased by \$1.4 million to \$37.1 million, primarily due to:

- interest on new financings issued in 2004 to fund capital expenditures in Utilities operations.

Interest expense for the year ended December 31, 2004, increased by \$1.1 million to \$144.9 million, primarily due to:

- interest on new financings issued in 2004 to fund capital expenditures in Utilities operations.

Interest and other income for the three months ended December 31, 2004, decreased by \$1.5 million to \$4.4 million, primarily due to:

- lower rates of interest earned.

Interest and other income for the year ended December 31, 2004, decreased by \$0.6 million to \$9.4 million, primarily due to:

- lower rates of interest earned.

Income taxes for the three months ended December 31, 2004, decreased by \$3.6 million to \$19.8 million, primarily due to:

- lower income tax rates; and
- a favourable one-time tax adjustment in 2004 for ATCO Gas, resulting from a change in income tax methodology as directed by the AEUB in the ATCO Gas Decision.

This decrease was partially offset by:

- a favourable one-time tax adjustment in 2003 for ATCO Pipelines, resulting from a change in income tax methodology as directed by the AEUB in the ATCO Pipelines Decision.

Income taxes for the year ended December 31, 2004, **including** the \$8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, decreased by \$10.1 million to \$97.2 million.

Income taxes for the year ended December 31, 2004, **excluding** the \$8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, decreased by \$18.3 million to \$89.0 million, primarily due to:

- lower income tax rates; and
- a favourable one-time tax adjustment in 2004 for ATCO Gas.

This decrease was partially offset by:

- a favourable one-time tax adjustment in 2003 for ATCO Pipelines.

Segmented Information

Segmented revenues for the three months and for the year ended December 31, 2004, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2004	2003	2004	2003
	(unaudited)			
Utilities (1).....	297.7	647.8	1,788.8	2,533.6
Power Generation	74.1	82.1	292.3	319.2
Intersegment eliminations.....	(0.1)	(1.8)	(2.4)	(6.6)
Total.....	371.7	728.1	2,078.7	2,846.2

Note:

(1) Includes the reduction in revenues from the Transfer of the Retail Energy Supply Businesses for the three months and for the year ended December 31, 2004.

Segmented earnings attributable to Class A and Class B shares for the three months and for the year ended December 31, 2004, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2004	2003	2004	2003
	(unaudited)			
Utilities (1).....	38.6	38.7	168.6	118.3
Power Generation (2).....	14.6	15.7	51.7	56.5
Corporate and Other	0.3	-	1.3	-
Intersegment eliminations.....	-	-	-	-
Total.....	53.5	54.4	221.6	174.8

Notes:

(1) The earnings for the year ended December 31, 2004, include earnings of \$55.1 million from the Transfer of the Retail Energy Supply Businesses.

(2) 2003 earnings have been restated for a retroactive change in the method of accounting for asset retirement obligations.

Utilities

Revenues from Utilities operations for the three months ended December 31, 2004, decreased by \$350.1 million to \$297.7 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses; and
- warmer temperatures in ATCO Gas, which were 9.8% warmer than normal, compared to 3.2% warmer than normal for the corresponding period in 2003.

This decrease was partially offset by:

- the ATCO Pipelines Decision (refer to Regulatory Matters - ATCO Pipelines section).

Revenues for the year ended December 31, 2004, decreased by \$744.8 million to \$1,788.8 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower prices of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas, which were 3.0% warmer than normal, compared to 3.4% colder than normal in 2003; and
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- customer additions in ATCO Gas; and
- the ATCO Pipelines Decision.

Earnings for the three months ended December 31, 2004, decreased by \$0.1 million to \$38.6 million, primarily due to:

- higher transportation costs in ATCO Pipelines;
- warmer temperatures in ATCO Gas; and
- the ATCO Gas Decision (refer to Regulatory Matters - ATCO Gas section).

This decrease was partially offset by:

- the ATCO Pipelines Decision.

Earnings for the year ended December 31, 2004, **including** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, increased by \$50.3 million to \$168.6 million.

Earnings for the year ended December 31, 2004, **excluding** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses, decreased by \$4.8 million to \$113.5 million, primarily due to:

- warmer temperatures in ATCO Gas;
- the ATCO Electric Decision (refer to Regulatory Matters - ATCO Electric section); and
- higher transportation costs in ATCO Pipelines.

This decrease was partially offset by:

- the ATCO Pipelines Decision;
- customer additions in ATCO Gas; and
- lower income tax rates.

Operating expenses for the year ended December 31, 2004, decreased by \$739.7 million to \$1,328.2 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses, and lower costs of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004;
- warmer temperatures in ATCO Gas; and

- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation costs) to transportation service only contracts (transportation costs).

This decrease was partially offset by:

- customer additions in ATCO Gas;
- higher transportation costs in ATCO Pipelines; and
- higher franchise fees in ATCO Gas.

In the first quarter of 2003, ATCO Gas commenced the first phase of a \$278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The ATCO Gas Decision approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program. The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

On August 30, 2004, ATCO Electric completed construction of a \$99.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake. The project included three substations and the expansion of an existing substation. Construction was completed in 10 months. Typically, a project of this scale and complexity is constructed over two years.

Power Generation

Revenues from power generation operations for the three months ended December 31, 2004, decreased by \$8.0 million to \$74.1 million, primarily as a result of:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher capacity and energy charges in Alberta Power (2000).

Revenues for the year ended December 31, 2004, decreased by \$26.9 million to \$292.3 million, primarily as a result of:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

This decrease was partially offset by:

- higher capacity and energy charges in Alberta Power (2000).

Earnings for the three months ended December 31, 2004, decreased by \$1.1 million to \$14.6 million, primarily due to:

- lower cost of service revenues in Alberta Power (2000) for the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

Earnings for the year ended December 31, 2004, decreased by \$4.8 million to \$51.7 million, primarily due to:

- lower cost of service revenues in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

Operating expenses for the year ended December 31, 2004, decreased by \$22.4 million to \$125.5 million, primarily due to:

- reduced operating and maintenance costs in Alberta Power (2000) from the H.R. Milner generating plant which was sold by the Alberta Balancing Pool on January 29, 2004.

During the three months ended December 31, 2004, Alberta Power (2000)'s **deferred availability incentive** account increased by \$8.1 million to \$46.1 million. The increase was primarily due to additional availability incentive payments received for improved plant availability. During the three months ended December 31, 2004, the amortization of deferred availability incentives, recorded in revenues, increased by \$0.2 million to \$2.0 million.

During the year ended December 31, 2004, the **deferred availability incentive** account increased by \$2.8 million to \$46.1 million. The increase was primarily due to the Battle River arbitration decision (refer to Business Risks-Alberta Power (2000) section), partially offset by amortization of deferred availability incentives, recorded in revenues, of \$7.6 million.

On January 29, 2004, the H.R. Milner generating plant was sold by the Alberta Balancing Pool to a third party and the contract under which Alberta Power (2000) had operated the plant on a cost of service basis since January 2001 was terminated. As part of the sale, Alberta Power (2000) was relieved of all decommissioning and reclamation obligations, including any environmental liabilities.

REGULATORY MATTERS

Regulated operations are conducted by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of the Corporation.

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005. The AEUB also announced that the 2005 generic return on equity would only apply to utilities which file rate applications in 2005. If no rate applications are filed, then existing return on common equity rates will continue to apply.

ATCO Electric

In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by \$83.0 million for 2003. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, a return on common equity of 9.60% and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric was allowed to earn a return on by \$22.3 million for 2004 as compared to 2003.

ATCO Electric's October 2, 2003, and July 2, 2004, decisions are referred to in this MD&A as the "ATCO Electric Decision".

ATCO Gas

In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB in its generic cost of capital decision for determining the return on common equity will be applied beginning in 2005.

ATCO Gas' October 1, 2003, and July 2, 2004, decisions are referred to in this MD&A as the "ATCO Gas Decision".

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for \$6.6 million (excluding costs of disposition) and allocated \$4.1 million of the proceeds to customers and \$1.8 million to ATCO Gas. In January 2004, the Alberta Court of Appeal overturned this decision and directed the AEUB to allocate \$5.4 million of the proceeds to ATCO Gas. The City of Calgary has appealed this decision to the Supreme Court of Canada, which has also granted ATCO Gas leave to cross-appeal the decision. Accordingly, ATCO Gas has not yet recorded the impact of the Alberta Court of Appeal decision.

In March 2004, the AEUB directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005, and allowed ATCO Midstream to continue to utilize the remaining uncontracted capacity at a rate of \$0.45 per gigajoule, up from \$0.41 per gigajoule. ATCO Gas has been granted leave to appeal this AEUB decision to the Alberta Court of Appeal. A hearing date has not yet been determined.

In July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the Carbon storage facility.

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances that have impacted ATCO Gas' deferred gas account. The application requests a recovery of approximately \$11.3 million from ATCO Gas' south customers, and a refund of approximately \$2.0 million to ATCO Gas' north customers. A decision from the AEUB is expected in the second quarter of 2005.

ATCO Pipelines

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress.

In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

ATCO Pipelines' December 2, 2003, July 2, 2004, and July 13, 2004, decisions are referred to in this MD&A as the "ATCO Pipelines Decision".

The AEUB has announced that it will hold a hearing to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. This hearing is not expected to be held until 2006.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations for the three months ended December 31, 2004, decreased by \$0.8 million to \$111.9 million, primarily due to:

- a refund to customers by ATCO Gas as a result of a change in income tax methodology as directed by the AEUB in the ATCO Gas Decision, which reduced cash flow from operations in 2004 by \$16.5 million (the "ATCO Gas Refund").

This decrease was partially offset by:

- increased availability incentives in Alberta Power (2000), primarily due to availability incentive payments received for improved plant availability; and
- a refund to customers by ATCO Pipelines as a result of a change in income tax methodology as directed by the AEUB in the ATCO Pipelines Decision, which reduced cash flow from operations in 2003 by \$5.4 million (the "ATCO Pipelines Refund").

Cash flow from operations for the year ended December 31, 2004, decreased by \$5.9 million to \$382.6 million, primarily due to:

- the ATCO Gas Refund.

This decrease was partially offset by:

- increased availability incentives in Alberta Power (2000); and
- the ATCO Pipelines Refund.

Investing for the three months ended December 31, 2004, increased by \$16.6 million to \$112.2 million, primarily due to:

- decreased proceeds on disposal of property, plant and equipment; and
- reductions in non-current deferred electricity costs.

This increase was partially offset by:

- lower capital expenditures.

Capital expenditures for the three months ended December 31, 2004, decreased by \$4.7 million to \$136.1 million, primarily due to:

- lower investment in regulated electric transmission projects.

This decrease was partially offset by:

- increased investment in regulated natural gas transportation and distribution projects.

Investing for the year ended December 31, 2004, increased by \$59.3 million to \$389.9 million, primarily due to:

- higher capital expenditures;
- reductions in non-current deferred electricity costs; and
- decreased proceeds on disposal of property, plant and equipment.

This increase was partially offset by:

- changes in non-cash working capital; and
- proceeds from the Transfer of the Retail Energy Supply Businesses.

Capital expenditures for the year ended December 31, 2004, increased by \$75.0 million to \$458.3 million, primarily due to:

- increased investment in regulated electric transmission projects.

During the three months ended December 31, 2004, the Corporation **issued**:

- \$100.0 million of 5.096% Debentures due November 18, 2014; and
- \$200.0 million of 5.896% Debentures due November 20, 2034.

During the three months ended December 31, 2004, the Corporation **redeemed**:

- \$96.0 million of notes payable.

These changes resulted in a **net debt increase** of \$204.0 million.

During the year ended December 31, 2004, the Corporation **issued**:

- \$180.0 million of 5.432% Debentures due January 23, 2019;
- \$100.0 million of 5.096% Debentures due November 18, 2014; and
- \$200.0 million of 5.896% Debentures due November 20, 2034.

During the year ended December 31, 2004, the Corporation **redeemed**:

- \$100.0 million of 8.73% Debentures 1994 Series due June 1, 2004.

These changes resulted in a **net debt increase** of \$380.0 million.

A planned issue of \$180.0 million of debentures by the Corporation in 2003 was deferred until January 2004 pending clarification of one of the Corporation's credit ratings. As a result of the uncertainty surrounding the timing of the receipt of the credit rating, the Corporation borrowed an additional \$150 million from its parent corporation, on behalf of ATCO Gas and ATCO Electric. In January 2004, the amounts advanced to ATCO Gas and ATCO Electric were repaid from the proceeds of the Corporation's \$180.0 million issue of 5.432% Debentures.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately \$425 million in 2005. These expenditures are uncommitted and relate primarily to utility operations.

Contractual obligations for the next five years and thereafter are as follows:

Contractual Obligations	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
	(\$ Millions)				
Long term debt.....	2,062.5	125.0	229.5	225.0	1,483.0
Operating leases.....	39.2	8.1	15.1	10.5	5.5
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1).....	7.0	1.4	1.4	1.4	2.8
Alberta Power (2000) coal purchase contracts (2).....	881.7	43.5	90.6	96.1	651.5
Alberta Power (2000) capital expenditures (3).....	9.7	9.7	-	-	-
ATCO Electric capital expenditures (4).....	17.8	17.8	-	-	-
Other.....	16.8	16.8	-	-	-
Total.....	3,034.7	222.3	336.6	333.0	2,142.8

Notes:

- (1) ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate mostly to storage purchases and operational contracts pertaining to the Carbon storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2004, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. The cost of natural gas purchased under these obligations is recoverable from ATCO Gas' customers.
- (2) Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.
- (3) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.
- (4) ATCO Electric has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At December 31, 2004, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
	(\$ Millions)		
Short term committed.....	300.0	17.0	283.0
Uncommitted.....	29.1	0.2	28.9
Total.....	329.1	17.2	311.9

In the third quarter of 2004, following a review of the Corporation's ongoing cash requirements, the Corporation reduced its uncommitted lines by \$85.0 million. This reduction was due primarily to reduced credit needs following the Transfer of the Retail Energy Supply Businesses earlier in the year.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

Future income tax liabilities of \$64.8 million at December 31, 2004, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of \$750.0 million of debentures over the twenty-five month life of the prospectus.

- On January 23, 2004, CU Inc. issued \$180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.
- On November 18, 2004, CU Inc. issued \$100.0 million of 5.096% Debentures due November 18, 2014, at a price of 100 to yield 5.096% and \$200.0 million of 5.896% Debentures due November 20, 2034, at a price of 100 to yield 5.896%. The proceeds of the issues were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

OUTSTANDING SHARE DATA

At February 25, 2005, the Corporation had outstanding 134 Class A shares and 76 Class B shares, all of which are owned by Canadian Utilities Limited.

TRANSACTIONS WITH RELATED PARTIES

The Corporation had the following transactions with affiliated corporations in 2004:

Entity	Relationship	Transaction	Recorded As	Amount (\$ Millions)
Canadian Utilities Limited (1)	Parent	Sale of electricity and natural gas, lease of land, rent and office services	Revenues	0.5
		Administration, rent, aircraft usage, bank activity charges, computer operations and systems development, financial management, and payroll and accounting services	Operation and maintenance, selling and administrative	7.1
		Purchase of equipment, leasehold improvements and capitalized software	Property, plant and equipment	0.7
ATCO Ltd. and ATCO Investments Ltd.	Affiliates	Corporate signature rights and rent	Selling and administrative	2.6
ASHCOR Technologies Ltd., ATCO Frontec Corp., ATCO I-Tek Inc. (1), ATCO I-Tek Business Services Ltd., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Utility Services Ltd., and Genics Inc.	Affiliates	Natural gas storage, transportation and other gas services, sale of electricity, rent and office services	Revenues	16.4
		Purchase and storage of natural gas	Natural gas supply	218.1
		Purchase of natural gas	Operation and maintenance	9.2
		Gas management fees, computer operations and systems development, call centre and customer billing services, information services, property management and security services, contract labor, payroll and accounting services	Operation and maintenance, selling and administrative	84.5
		North Warning System joint venture earnings	Other income	0.1
		Purchase of equipment, capitalized costs and capitalized software	Property, plant and equipment	21.7

Note:

(1) Effective January 1, 2004, the ATCO I-Tek division of Canadian Utilities Limited was incorporated as ATCO I-Tek Inc. Therefore, the Corporation's related party transactions with ATCO I-Tek Inc. in 2004 are reported as transactions with an affiliate corporation rather than with the parent corporation.

The Corporation incurred advertising and promotion expenses from an entity related through common control totaling \$0.2 million.

These transactions are in the normal course of business and under normal commercial terms.

BUSINESS RISKS

On February 16, 2005, the Kyoto Protocol came into effect. The Corporation is unable to determine what impact, if any, the protocol will have on its operations as the Government of Canada has not yet released its implementation plan. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Transfer of the Retail Energy Supply Businesses

Although ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, ATCO Gas and ATCO Electric remain legally obligated to perform these functions if DEML fails to perform. If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric. In the event of a reversion of such functions, ATCO Gas and ATCO Electric could incur costs related to commodity procurement, transportation and delivery charges and various regulatory costs.

Centrica plc, DEML's parent, has provided a \$300 million guarantee, supported by a \$235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

As a result of the agreements with DEML, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

Late Payment Penalties on Utility Bills

As a result of recent decisions of the Supreme Court of Canada in *Garland vs. Consumers' Gas Co.*, the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

Alberta Power (2000)

Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's were based.

Under the terms of the PPA's, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA's, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA's. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

At December 31, 2004, the Corporation had recorded \$46.1 million of deferred availability incentives.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

In August 2004, an arbitration tribunal appointed under the Battle River Power Purchase Arrangement ("Battle River PPA") determined that Alberta Power (2000) was entitled to recover \$10.4 million of availability penalty payments, plus interest, from EPCOR Utilities Inc. ("EPCOR"), the counterparty to the Battle River PPA, due to short term curtailed plant production during the first quarter of 2003 caused by unprecedented drought conditions. The \$10.4 million of availability penalty payments plus interest, less costs associated with the arbitration proceedings, was recorded in Alberta Power (2000)'s deferred availability incentive balance sheet account and had no effect on Alberta Power (2000)'s 2004 earnings.

In June and July 2004, the Battle River generating plant's water levels were below those of 2003, which required the Corporation to limit generation to avoid exceeding the environmental license temperature limitations. The Corporation made force majeure claims for the period June 24, 2004, to July 4, 2004, and the period July 13, 2004 to July 26, 2004. The Corporation claimed \$7 million with respect to these claims and was successful in reaching a negotiated settlement with EPCOR and the Alberta Balancing Pool in December 2004 for \$5.2 million. The remaining \$1.8 million and related costs of \$0.2 million were recorded as a reduction to Alberta Power (2000)'s

deferred availability incentive balance sheet account. The settlement had no effect on Alberta Power (2000)'s 2004 earnings.

Contingencies

The Corporation is party to a number of disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Insurance Coverage

A number of U.S. insurance companies are the subject of lawsuits and investigations into their business and accounting practices by the Attorney General of the State of New York and the U.S. Securities and Exchange Commission. Certain of these insurers provide a portion of the Corporation's insurance coverage. The Corporation is unable at this time to determine what impact, if any, these investigations may have on the ability of the insurers mentioned to pay any corporate insurance claims which may arise.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to \$165.3 million at December 31, 2004. This balance includes \$38.8 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to \$126.5 million, is expected to be recovered from utility customers through inclusion in future rates. There are tax loss carryforwards of \$0.9 million for which no tax benefit has been recorded. These losses will expire in 2011.

In addition, the Corporation uses various derivative instruments to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. Note 18 to the financial statements sets out the instruments in place at December 31, 2004.

Other than the foregoing, the Corporation does not have any off-balance sheet arrangements that have, or are likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives and asset retirement obligations, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates. The Corporation's critical accounting estimates are discussed below.

Deferred Availability Incentives

As noted previously in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2004, the Corporation had recorded \$46.1 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to \$7.6 million in 2004.

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately \$4.1 million, whereas the low case scenario would have resulted in lower revenues of approximately \$2.9 million.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2004, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations on accounting for asset retirement obligations as described below. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000).

The effect of adopting these recommendations is presented as increases (decreases) below:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2004	2003	2004	2003
	<i>(unaudited)</i>			
<i>Statement of earnings</i>				
Depreciation and amortization.....	(0.2)	(0.3)	(1.0)	(1.8)
Accretion expense, included in depreciation and amortization	0.4	0.3	1.5	1.4
Earnings attributable to Class A and Class B shares	(0.2)	-	(0.5)	0.4

**January 1
2003**

(\$ Millions)

Balance sheet

Retirement assets and site restoration and removal costs, included in property, plant and equipment.....	20.4
Asset retirement obligations, included in deferred credits.....	24.5
Retained earnings at beginning of period	(4.1)

Changes in asset retirement obligations are summarized below:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2004	2003	2004	2003
	<i>(unaudited)</i>			
Obligations at beginning of period	27.0	25.6	25.9	24.5
Accretion expense.....	0.4	0.3	1.5	1.4
Obligations at end of period	27.4	25.9	27.4	25.9

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$63 million, which will be incurred between 2005 and 2026. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings for the three months and year ended December 31, 2004.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations that define the primary sources of GAAP. Adoption of these recommendations had no effect on earnings for the three months and year ended December 31, 2004. While CICA recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP. Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the regulator renders a subsequent decision. The Corporation anticipates that there would be no material differences between the amounts approved by the regulator for collection or refund and the amounts included in assets or liabilities on the balance sheet. The Corporation has chosen to retain its existing accounting policies, as permitted by CICA

recommendations that define the primary sources of GAAP, pertaining to regulatory decisions that give rise to deferred assets or liabilities.

Effective January 1, 2005, the Corporation intends to prospectively adopt the CICA's accounting guideline on the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities and, if so, to consolidate them. The Corporation is currently evaluating the impact of the guideline.

February 24, 2005